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Costs To Reduce Sulfur Dioxide Emissions

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BACKGROUND

Despite the widespread attention the acid rain issue has received from the scientific community and in public and political forums, basic questions concerning the causes and effects of acid precipitation remain unanswered. Inadequately explained at present are the origins, transformation processes, and long-range transport patterns of chemical species that can cause precipitation to be acidic. In addition, our understanding of the impacts of acidic precipitation on terrestrial and aquatic ecosystems is only beginning to be developed. Nonetheless, observations of rainfall with greater than expected levels of acidity and of lakes with high acidic content have prompted calls for action, particularly from the northeastern U.S. and southeastern Canada.

It appears that the target of those calling for immediate action are coal-fired electric powerplants. The main rationale for this targeting appears to be the fact that these powerplants are a major source of sulfur dioxide emissions in the United States and that winds generally blow from west to east. Most of the existing coal-fired powerplants are located in the Midwest and the likely targets are those burning medium or high sulfur coals. Almost all of these powerplants were built prior to regulations requiring installation of sulfur dioxide control equipment on all new powerplants.

A Note on Format:

Throughout the report, the right-hand page displays a chart or series of important concepts, accompanied by supporting text on the left-hand page. This format is designed to facilitate use of the document as a briefing package.

BACKGROUND

- IT IS GENERALLY RECOGNIZED THAT THERE ARE MAJOR UNCERTAINTIES AS TO THE CAUSE AND EFFECTS OF ACIDIC PRECIPITATION.

- NEVERTHELESS, CONCERN OVER POSSIBLE DETRIMENTAL EFFECTS HAS CAUSED GROUPS WITHIN THE UNITED STATES, AS WELL AS THE CANADIAN GOVERNMENT, TO CALL FOR A REDUCTION IN GROSS (OVERALL) EMISSION LEVELS OF SULFUR AND NITROGEN OXIDES.

- THE FOCUS OF THOSE CALLING FOR IMMEDIATE CONTROLS HAS BEEN COAL-FIRED ELECTRIC POWERPLANTS.

  - PRIMARILY LOCATED IN THE MIDWEST
  - CURRENTLY BURNING MODERATELY HIGH OR HIGH SULFUR COALS
  - BUILT PRIOR TO REGULATIONS REQUIRING THE USE OF SULFUR OXIDE CONTROL EQUIPMENT (SCRUBBERS)

PURPOSE OF BRIEFING

Central to the resolution of the acid rain issue are debates about the costs and benefits of controlling man-made emissions of chemicals that may cause acid rain. In this briefing, we shall examine the position of those who are calling for immediate action and implicating coal-fired powerplants as the cause of the problem. We shall present the costs of controlling sulfur dioxide emissions using alternative control methods available today. We shall not, however, attempt to calculate the benefits of reducing these emissions since insufficient information is available to provide even a rough estimate.

This presentation will proceed in two steps. First, costs will be presented as obtained through straightforward calculations based upon simplifying but realistic assumptions. The advantages of these straightforward calculations is that they provide intuitive insight into the factors that drive the overall costs.[1] Next, we shall summarize the costs of sulfur dioxide control obtained through several large-scale analyses and compare these results with those obtained through our straightforward methods.

It is important to recognize that this briefing does not present the costs of acid rain control, but rather the costs of measures being proposed by advocates of immediate control. From the scientific and technical information available to us, we are not able to relate sulfur dioxide control levels to benefits associated with alleviating acidic precipitation.

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[1]Descriptions of the algorithms used are detailed in the Appendix.

PURPOSE OF BRIEFING

- TO PRESENT AND REVIEW COSTS OF REDUCING THE LEVELS OF SULFUR OXIDES FROM UTILITY POWERPLANTS CURRENTLY BURNING COAL.

  - CONSTITUTES A PRESENTATION OF THE COST HALF OF THE COST/BENEFIT EQUATION

- TO PROVIDE INSIGHT ON THE FACTORS WHICH CONTROL THESE COSTS.

  - WILL COMPARE RESULTS OBTAINED THROUGH STRAIGHTFORWARD CALCULATIONS WITH THOSE OBTAINED FROM ECONOMETRIC MODELS OF THE UTILITY SECTOR

SCOPE OF ANALYSIS

This briefing is limited to examining the costs of controlling sulfur dioxide emissions beyond the levels required by the Clean Air Act. The primary reason for imposing such additional controls would be to address the acid precipitation issue, if the benefits of such controls were found to be commensurate with the costs. In the context of acid precipitation, it is important to recognize that sulfur dioxide emissions from coal-fired powerplants may not be the only precursor pollutant of concern. There exist other sources of atmospheric sulfates, and other pollutants e.g., oxidants, may regulate the rate of acid formation. Also, nitrogen dioxide emissions form acidic compounds in the atmosphere.

The analyses that underlie the costs presented in this briefing are limited to the utility sector, in particular, to coal-fired utilities. These utilities are a major source of sulfur dioxide emissions in the United States. In addition, utility powerplants are fairly large. Therefore, we generally expect that control of such sources will incur lower costs per ton of reduction than, for example, control of industrial boilers. It appears that these are the reasons why advocates of immediate controls have focused their efforts on this sector. Therefore, by looking at utilities, we can obtain an appreciation of the cost implications of moving towards early control and accepting their assumption that gross regional emission reductions are the answer.

Finally, to be practical, we shall consider only currently available control methods. There are alternative control technologies in the R&D pipeline. However, we expect none of them to be available for widespread commercial use for at least five years and possibly much longer. Therefore, no decision on controlling sulfur dioxide emissions should be predicated on obtaining a low-cost technological "fix."

SCOPE OF ANALYSIS

- LIMITED TO SO_2 CONTROL
  - OPTIMISTIC ASSUMPTION THAT SO_2 IS THE ONLY PRECURSOR POLLUTANT AT ISSUE
  - OTHER POLLUTANTS, SUCH AS NO_x, ARE KNOWN TO FORM ACIDIC COMPOUNDS IN THE ATMOSPHERE; THUS, THIS ANALYSIS DOES NOT PRESENT TOTAL POTENTIAL CONTROL COSTS
- LIMITED TO THE UTILITY SECTOR
  - MAJOR SOURCE OF SO_2 EMISSIONS IN THE U.S.
  - EXPECT CONTROL COSTS TO BE LOWEST IN THIS SECTOR IF GROSS EMISSION REDUCTIONS ARE THE ANSWER.
- LIMITED TO AVAILABLE METHODS
  - COAL SWITCHING
  - FLUE GAS DESULFURIZATION
  - COAL CLEANING
- IT IS UNLIKELY THAT OTHER TECHNOLOGIES NOW IN THE R&D PIPELINE WILL BE AVAILABLE FOR WIDESPREAD USE FOR AT LEAST FIVE YEARS.

APPROACH

The analysis reported in this briefing consists of two phases. First, the results of straightforward calculations will be presented. This will be followed by a review and comparison of contractor studies based upon more complicated methodologies. We are able to use a simplified calculation scheme because the dominant factors which drive the costs of each of the control methods can be identified and simplified assumptions can be made. These assumptions are realistic as long as we recognize that the resultant costs apply "on the average" and are willing to accept a range of costs rather than a single number. The advantage of the straightforward calculations is that the assumptions that underlie them are clear. If there is a disagreement with the costs presented, a rational discussion centered on the underlying assumptions can take place.

One of the assumptions that drives this straightforward analysis is that each of the three control methods examined is most cost-effective when applied to higher sulfur coals. "Cost-effective" means the lowest costs per ton of sulfur dioxide controlled. This assumption is intuitively obvious once the technical aspects of each of the control methods are examined. In addition, this assumption has been verified by a number of more complicated analyses.

Accepting this assumption, we have examined the cost of each of the three control methods when applied to all coals that have a sulfur content of greater than three percent and to all coals that have sulfur content greater than two percent. In both cases, we examined only coals used by utilities in the contiguous 48 states for electricity generation.

Because we are deriving costs for the more cost-effective opportunities to reduce overall sulfur emissions, it is important to recognize that these costs represent the minimum costs that can be anticipated based upon the performance of currently available control technologies. Such low costs may not be achievable using regulatory approaches. This will be discussed at greater length later in the briefing.

I. STRAIGHTFORWARD CALCULATIONS

- PROVIDES INSIGHT INTO UNDERLYING COSTS
- BASED UPON ASSUMPTION THAT EACH OF THE CONTROL METHODS IS MOST COST-EFFECTIVE WHEN APPLIED TO HIGHER SULFUR COALS
  - THIS ASSUMPTION HAS BEEN VERIFIED IN A LARGE NUMBER OF ECONOMETRIC STUDIES OF ENVIRONMENTAL CONTROL OPTIONS
- COST ESTIMATES ARE PROVIDED FOR TWO CASES:
  - CONTROLS ON ALL COALS GREATER THAN 3 PERCENT SULFUR
  - CONTROLS ON ALL COALS GREATER THAN 2 PERCENT SULFUR
- NOT A REGULATORY ANALYSIS BUT RATHER AN ANALYSIS OF MINIMUM COSTS BASED ON TECHNICAL LIMITATIONS
  - CRAFTING A REGULATORY STRATEGY TO ACHIEVE THE RESULTS SHOWN MAY NOT BE POSSIBLE

II. REVIEW OF AND COMPARISON WITH MODEL-BASED ANALYSIS

- BASED UPON POTENTIAL REGULATORY STRATEGIES
- PROVIDES INSIGHT INTO DISECONOMIES OF SCALE

ESTIMATE OF SULFUR AND NITROGEN DIOXIDE EMISSIONS

This chart is presented to illustrate a few key points relevant to any analysis associated with controlling sulfur dioxide emissions beyond currently mandated levels.

First, if alleviating acid precipitation is the driving factor, it is important to note that nitrogen oxides can also contribute to precipitation acidity. From both a global and U.S. perspective, nitrogen oxide emission levels are comparable to those of sulfur dioxide. In fact, a third to one-half of the measured acidity in the northeastern United States and southeastern Canada has been associated with nitrates. Although nitrogen oxides appear to play an important role in acid precipitation, an analysis of the costs associated with nitrogen oxide control is beyond the scope of this report.

Looking at just the sulfur dioxide column, it is evident that natural sources of sulfur dioxide are at least as important as manmade sources if we take a world-wide inventory. Comparing the global and U.S. totals, global emissions are at least 15 times greater than those of the United States. This fact is raised to emphasize the possibility that global emissions could reduce the effectiveness of any emission control program instituted in the United States. This, however, is but one of many uncertainties associated with understanding the benefits, if any, of reducing sulfur dioxide emission levels beyond those levels already required to protect human health and welfare.

Focusing only on the United States, it can be seen that coal-fired electric powerplants account for almost 60 percent of all U.S. manmade emissions of sulfur dioxide: 17 million tons of the approximately 30 million tons annually emitted in the United States.

Finally, it is important to recognize that the sources of emissions within the United States are not evenly distributed across the country, but rather are most prevalent in those states which have historically maintained a strong dependence upon coal. For example, coal-fired electric powerplants in ten states emitted more than two-thirds (or 12 million tons per year) of all sulfur dioxide emissions produced by coal electric powerplants within the United States.

Estimate of SO_2 and NO_x Emissions[1/]
(Millions of Short Tons Per Year)

Region/Source	SO_2	NO_x
Global		
Natural	300-500	50-750
Manmade (1976)	230	50-60
Total	530-730	100-810
USA (1978)		
Coal Powerplants	17	5
Other Manmade	13	17
Total	30	22
10 States[2/] (1978)		
Coal Powerplants	12	2.6
Other Manmade	6	1.4
Total	18	4

1/ References for all charts are listed in the Appendix.

2/ See map on page 13.

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MAP OF THE TEN STATE REGION

This map shows the location of the ten states mentioned on the previous slide. These states are contiguous and primarily located in the Midwest. In this region, the coal industry mines nearly all of the high sulfur coal produced in this country. For this reason, it is not unreasonable to find that these ten states generate approximately two-thirds of the national emissions of sulfur dioxide.

From the perspective of cost-effective control of overall sulfur dioxide emissions, these ten states play an even more dominant role. For example, in the minimum cost approach followed in our simple analysis, only utilities burning high sulfur coals (either greater than two percent or greater than three percent) will be affected. Almost all of these utilities are located in this ten state region. This is qualitatively shown in the next chart.

Map of the Ten State Region

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DISTRIBUTION OF HIGH SULFUR COAL BURNING UTILITIES

This chart shows the amount of coal (in millions of tons) annually consumed by utilities in 1980. In all, utilities consumed approximately 590 million tons of coal. From this total, approximately 200 million tons had a sulfur content of greater than two percent, of which 100 million tons had a sulfur content of greater than three percent. However, more than 80 percent of coals used by utilities with a sulfur content of greater than two percent was consumed in the same 10 state region shown on the preceding map.

The implications of this distribution are that the cost of any attempt to further reduce sulfur oxide emissions will be almost completely borne by just ten states. For example, between 83 and 92 percent of the costs that we shall present would be borne by these states if a national "minimum cost" strategy were implemented.

Distribution of High Sulfur Coal Burning Utilities
[In Million Tons of Coal Annually Consumed]

REGION / COAL TYPE	10 STATES	48 STATES
Greater Than 3% S	87 (92%)	95
Greater Than 2% S	163 (83%)	197
All Coals Consumed by Utilities		594

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COST CALCULATIONS

Page 17 shows the key input variables for the straightforward calculation scheme used in this analysis. Using information on the sulfur content of coals currently used by powerplants, we are able to calculate the average sulfur content for each of the two coal categories for which we will calculate control costs.

The key cost factors for coal switching, flue gas desulfurization, and coal cleaning are shown on the lower portion of the chart. Note that the cost factors for coal switching include not just the direct costs associated with purchasing more expensive coal and upgrading equipment but also the factor (miner productivity) that drives an indirect cost associated with displacing coal tonnage and therefore coal miners from their current jobs. The cost factors for flue gas desulfurization include the energy penalty associated with operating scrubber equipment, but do not include the costs of spare scrubber modules installed to ensure system reliability. The cost factor for coal cleaning assumes that capital costs associated with increasing coal production capacity as well as costs for transporting the coal are included in the higher purchase price.

Each of these input variables, with references where appropriate, and the actual calculations are explained in the Appendix to this briefing. It is merely a matter of simple arithmetic to check our calculations or to repeat them with different values for the cost factors.

COST CALCULATIONS: INPUT VARIABLES

Weighted Average Sulfur Content:[1]

All coals greater than 3 percent sulfur: 3.6 percent
All coals greater than 2 percent sulfur: 3.1 percent

Cost Factors:[2]

- Coal Switching: Switch to 1 percent sulfur coal

  Additional Coal Costs: $6 to $12 per ton--greater than 3 percent sulfur coal
  $4 to $10 ton--between 2 and 3 percent sulfur coal

  Capital Costs: $21 to $50 per kw capacity--upgrading equipment
  Miner Productivity: 9 tons of coal per man/day for deep-mined coal
  28 tons of coal per man/day for surface-mined coal

- Flue Gas Desulfurization: 85 percent removal

  Capital Costs: $140 to $250 per kw capacity
  O&M Costs: 3 to 6 mills per kwh

- Coal Cleaning: 20 percent removal

  Additional Coal Costs: $3 to $5 per ton

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[1] See Appendix pages 3-4 for calculations.

[2] See Appendix pages 5-10 for calculations.

SUMMARY OF CALCULATIONS

The results of our straightforward analysis are shown on this chart. We have chosen to report costs in terms of 1980 dollars per million tons of sulfur dioxide annually removed. A million tons represents approximately three percent of total U.S. sulfur dioxide emissions and between five and six percent of the emissions emanating from the ten state region we discussed earlier.

The second column shows the additional operating costs in millions of dollars per year associated with each control method. These costs represent funds that would be expended during each year that the control method would be in effect. For coal switching and coal cleaning, these costs would be incurred in purchasing higher priced coal. For flue gas desulfurization, the amount shown represents the annual costs associated with operating and maintaining a wet scrubber. These costs are shown in 1980 dollars; actual funds expended would be larger due to inflation, which is not explicitly considered in this analysis.

The third column provides the capital costs in billions of 1980 dollars. These costs are one-time expenditures and represent costs that electric utilities would incur to build scrubbing facilities or to update their equipment to handle low sulfur coal.

(continued)

Summary of Calculations
(Per Million Tons of SO_2 Removed Per Year)

	Coal Type (Greater Than)	O&M Costs ($ Million/Year)	Capital Costs ($ Billion)
Coal Switching	3% S Coal	$120 to 240	$0.17 to 0.41
	2% S Coal	$130 to 280	$0.21 to 0.50
Flue Gas Desulfurization	3% S Coal	$110 to 220	$1.0 to 1.7
	2% S Coal	$130 to 250	$1.1 to 2.0
Coal Cleaning	3% S Coal	$220 to 370	NA
	2% S Coal	$260 to 420	NA

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SUMMARY OF CALCULATIONS (continued)

Since each of these control methods involves a different combination of annual operating costs and one-time capital costs, it is difficult to compare one with another or with the other possible investment opportunities for these funds. For these reasons, annual and capital costs are often aggregated into a single number. There are two basic ways to do this: annual costs can be capitalized or capital costs can be annualized. In the former method, a quantity known as the "present value" is obtained which represents an equivalent lump sum (one-time) payment adequate to cover both capital and annual costs. In the latter method, a "total annualized cost" is obtained which represents an apportionment of the capital costs into annual payments. For those not familiar with these two methods, a more detailed description of each is included in the Appendix. The present value and total annualized costs of each of the three control methods are shown in the fourth and fifth columns of this chart.

Examining the present value column, our calculations indicate that a decision to reduce sulfur dioxide emissions by one million tons per year for a significant number of years (30 years in our example) has a cost with a present value between $2 and $6 billion. This large range is due in part to cost differences between the various control methods. The factor that dominates the spread in the reported cost range, however is the broad range of values used for each input variable. This was done purposely to emphasize real variations among actual electric utilities. These costs should be interpreted as minimum cost estimates since they are based upon technology limitations and do not reflect economic inefficiencies associated with implementing a specific regulatory approach.

If we consider a small reduction increment of no more than one or two million tons per year of sulfur dioxide emissions, we estimate that the present value of the "minimum cost" approach could be as low as $2 billion <u>per million tons annually removed</u>. The only way to achieve this "minimum cost estimate" would be to devise a regulation that looked at the entire utility sector and caused only those utilities with the lowest cost opportunities to reduce sulfur emissions to do so in the most cost-effective manner. The actual cost of real regulations could be considerably greater.

As higher reduction increments (e.g., 5 million tons per year) are sought, the average cost per million tons removed increases considerably, approaching the upper bounds of the ranges shown in the chart. This phenomenon of "diseconomies of scale" can be qualitatively explained as resulting when "easy opportunities" for applying each control method are used up. More difficult opportunities must then be employed on utility powerplants that require more expensive scrubbers or on plants that use expensive-to-clean or difficult-to-displace coal. In addition, increased demand for low sulfur coal would cause the price of all low sulfur coal supplies to increase.

Summary of Calculations
(Per Million Tons of SO_2 Removed Per Year)

	Coal Type (Greater Than)	O&M Costs ($ Million/Year)	Capital Costs ($ Billion)	Annualized Cost 1/ ($ Million/Year)	Present Value 1/ 2/ ($ Billion)
Coal Switching	3% S Coal	$120 to 240	$0.17 to 0.41	$130 to 270	$2.0 to 4.1
	2% S Coal	$130 to 280	$0.21 to 0.50	$140 to 310	$2.2 to 4.8
Flue Gas Desulfurization	3% S Coal	$110 to 220	$1.0 to 1.7	$170 to 330	$2.7 to 5.1
	2% S Coal	$130 to 250	$1.1 to 2.0	$200 to 380	$3.1 to 5.9
Coal Cleaning	3% S Coal	$220 to 370	NA	$220 to 370	$3.4 to 5.7
	2% S Coal	$260 to 420	NA	$260 to 420	$4.0 to 6.5

1/ Reflects a 5 percent discount rate (real) with a 30-year investment lifetime. See Appendix page 11 for an explanation of the equations used. Note that annualized costs calculated using a 5 percent discount rate may understate the capital cost component. A higher discount rate would change the ratio of the cost components such that capital costs would comprise a larger portion of the total annualized cost.

2/ Reflects the one-time costs associated with a million tons of annual SO_2 reductions over a period of 30 years.

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SUMMARY OF CALCULATIONS

INDIRECT COSTS

In addition to direct dollar costs, the coal switching control method involves major socio-economic costs. For every one million tons of sulfur dioxide annually removed through coal switching, between 20 and 25 million tons of higher sulfur coal will be displaced by low sulfur coal. An annual reduction of five million tons of sulfur dioxide would displace over 100 million tons of high sulfur coal, about one-eighth of the current coal production of the United States. The portion of the mining industry affected by such a switch would be located primarily in the northern Appalachian and Midwest regions where most of the coal over two percent sulfur is mined. At the same time, increased upward pressure would be placed upon prices for low sulfur coal during a period in which this coal would be in high demand for new industrial boilers and on the coal export market.

Displacing tonnage implies displacing miners from areas where they are now employed. The last column in the table on this chart indicates the number of miners that would be directly affected per million tons of sulfur dioxide annually reduced through coal switching. We estimate that there is no more than a 10 to 15 percent uncertainty in these numbers. We cannot claim that all of these miners would become unemployed; some may move to other coal mining areas, others may not. In fact, total mining employment may increase with the need to open new low sulfur coal mines, although the regional distribution of employment opportunities may change due to the location of the new mines.

Summary of Calculations
Indirect Costs

	Driving Assumptions	Tonnage of Coal Displaced Per Million Tons SO_2 Removed (Million Tons)3/	Miners Affected Per Million tons SO_2 Removed3/
>3%S coal	9 tons/man-day1/ 28 tons/man-day2/	20	5100
>2%S coal	240 man-days/year	25	6400

1/ Average miner productivity from deep mines. Approximately one-third of "high sulfur" coal (greater than 2 percent sulfur by weight) shipped to utilities is produced from deep mines.

2/ Average miner productivity from surface mines. Approximately two-thirds of "high sulfur" coal (greater than 2 percent sulfur by weight) shipped to utilities is produced from surface mines.

3/ See Appendix page 13 for calculations.

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ELECTRICITY COST INCREASES DUE TO SULFUR DIOXIDE EMISSION CONTROL

The ultimate impact of any sulfur dioxide control program aimed at the utility sector will be on consumers of electricity. To estimate the magnitude of the costs that consumers will see, we have calculated the implications of two sulfur dioxide reduction methods: 1) flue gas desulfurization; and 2) coal switching. The chart on page 17 presents estimates for the capital and O&M costs associated with each method. Annualized costs derived using these cost assumptions range between 3 and 9 mills per kilowatt-hour (see Appendix page 14). At the utility itself, this would represent an increase of between 9 and 46 percent over current generating costs.

The regulatory framework governing utility operations allows these additional costs to be passed directly to consumers. By the time transmission and distribution costs are added, consumers would see the 3 to 9 mill increase in busbar costs as no more than a 7 to 26 percent increase in their electricity bills. The actual increase in a consumer electricity bill would depend on the fraction of delivered electricity that is generated by powerplants forced to modify operation to control sulfur dioxide emissions.

Electricity Cost Increase Due to Sulfur Dioxide Emission Control

DRIVING ASSUMPTIONS	INCREMENTAL INCREASE IN GENERATION COST 3/	RANGE OF MAXIMUM INCREASE IN COSTS TO CONSUMER 4/
• 20 to 30 Mills/kwh electricity generation cost 1/ • 3 to 5.4 cents/kwh electricity cost to consumer 2/	2.6 to 9.1 Mills/Kwh	4 to 26%

1/ Busbar cost of electricity from existing powerplants firing high sulfur coal without scrubbers. (Note: 1 Mill = 0.1 Cent)

2/ The consumer cost includes generation, transmission, and distribution costs. The figures shown here represent rates paid by residential consumers in the ten-state region as of January 1, 1980.

3/ See Appendix page 14 for calculations.

4/ See Appendix page 16 for calculations.

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MAXIMUM POTENTIAL CONTROL METHOD EFFECTIVENESS

In this chart, we conclude the presentation of results obtained by our straightforward analysis scheme by showing the maximum potential of each of the control methods to reduce sulfur dioxide emissions. The assumptions that drive these calculations are listed in the chart: the calculations themselves are described in the Appendix. The first column of figures represents the number of million tons of sulfur dioxide emissions that could be controlled if the control method was applied to all coals greater than three percent sulfur used by utilities. The second column assumes the control method is applied to all coals greater than two percent sulfur.

Coal switching or flue gas desulfurization have the potential of reducing sulfur dioxide emissions by between five and ten million tons per year. Coal cleaning, however, is limited to total reductions of two million tons per year or less.

It should be emphasized that the figures shown represent absolute maximums based upon the assumptions shown and do not take into account feasibility constraints associated with particular electric powerplants. If reductions of the order of ten million tons per year or more are desired, it will almost surely be necessary to require additional controls on lower sulfur coals (i.e., below two percent sulfur), to further control industrial users of coal, or to require additional controls on non-coal related sources of sulfur dioxide emissions.

Maximum Potential Control Method Effectiveness
(Million Tons of SO_2 Per Year)

	Driving Assumptions	Maximum Potential Emission Reduction 2/ for > 3% S Coal	Maximum Potential Emission Reduction 2/ for >2% S Coal
Coal Switching	1% S coal replaces > 3% S coal (73% Removal) 1% S coal replaces > 2% S coal (68% Removal)	4.9	8.0
Flue Gas Desulfurization	85% Removal (> 3% S and > 2% S coals)	5.8	10
Coal Cleaning 1/	20% removal (> 3% S and > 2% S coals)	1.4	2.4

1/ Many of the coals under consideration are already being cleaned. Therefore, the emission reduction numbers shown represent over-estimates.

2/ The totals shown are not additive: each represents the emission reduction resulting from a single, mutually-exclusive control. See Appendix pages 17-18 for calculations.

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CONCLUSIONS: DOE ANALYSIS

Page 29 summarizes the major conclusions obtained from our analysis. First, substantial costs are associated with imposing sulfur dioxide control requirements beyond those already in effect. Costs range between $2 and $6 billion for each million tons of sulfur dioxide annually removed. Second, most of the spread in this range can be attributed to "diseconomies of scale." In particular, a small reduction goal could be met by searching for the least cost opportunities to reduce sulfur dioxide emissions and will correspond to costs in the lower portion of this range. As larger reduction increments are sought, these least cost opportunities will be used up and it will be necessary to turn to less cost-effective measures representing the upper portion of the calculated cost range. For example, more expensive scrubbers would have to be installed or expensive-to-clean coal would have to be used. In this context, it is important to note once again that the costs derived in this analysis are minimum costs in the sense that they are based solely upon technical considerations associated with highly cost-effective measures. Actual costs could be considerably higher due to site-specific constraints and/or economic inefficiencies associated with specific regulatory approaches.

Our calculations indicate a ranking of the three control methods, with coal switching being the least expensive (if we ignore indirect costs) and coal cleaning the most expensive. There is considerable overlap among the costs of the three control methods, however, and the cost ranking could be reversed for a particular powerplant at a specific site.

While the direct costs of each of the control methods are comparable, each method has unique problems. Coal cleaning has a serious drawback in that significant reductions of sulfur dioxide emissions cannot be achieved. Flue gas desulfurization also has its drawbacks. There are high capital requirements that would certainly strain the utility sector. In addition, because scrubbers have a long history of maintenance and reliability problems, produce significant quantities of solid waste, and result in decreased energy efficiency, they have not yet gained acceptance by many utilities. In the case of coal switching, relative shifts in the demand for low and high sulfur coals would have a significant impact on the coal industry, particularly through localized displacements of coal miners and increased costs to all low sulfur coal users.

CONCLUSIONS: DOE ANALYSIS

- THE CALCULATIONS YIELD DIRECT COSTS (PRESENT VALUE) COVERING A RANGE BETWEEN $2 AND $6 BILLION PER MILLION TONS SO_2 ANNUALLY REMOVED.

- THE SPREAD IN THIS RANGE CAN BE ATTRIBUTED TO "DISECONOMIES OF SCALE"

  - SMALL REDUCTION INCREMENTS CAN BE ACHIEVED THROUGH LOWER-COST OPPORTUNITIES FOR REDUCING EMISSIONS (CORRESPONDING TO THE LOWER PORTION OF THIS RANGE)

  - LARGE REDUCTION INCREMENTS REQUIRE MORE EXPENSIVE MEASURES FOR REDUCING EMISSIONS (CORRESPONDING TO THE UPPER PORTION OF THIS RANGE)

- DIRECT COSTS (NORMALIZED) ASSOCIATED WITH EACH OF THE CONTROL METHODS ARE COMPARABLE.

- COAL CLEANING CANNOT ACHIEVE SIGNIFICANT REDUCTIONS (I.E., GREATER THAN 1.5 MILLION TONS SO_2 ANNUALLY)

- BOTH FLUE GAS DESULFURIZATION AND COAL SWITCHING HAVE SIGNIFICANT "INDIRECT" COSTS

  - FLUE GAS DESULFURIZATION: CAPITAL AVAILABILITY, SOLID WASTE DISPOSAL, ENERGY EFFICIENCY LOSSES;

  - SWITCHING: DISPLACEMENT OF TONNAGE AND MINERS, INCREASED COSTS TO ALL LOW SULFUR COAL USERS.

RESULTS FROM CONTRACTOR STUDIES

Page 31 introduces the second phase of this report. Here the sulfur reduction cost estimates derived in the first phase are compared with three larger studies previously conducted for the Department of Energy and the Environmental Protection Agency to assess reduction strategies and costs.

Two of the contractor-performed studies relied upon econometric models of the utility sector. Both of these studies derived costs for distinct regulatory approaches. A third study supplemented these two studies by compiling plant specific data to derive the costs of various levels of sulfur dioxide control. This supplementary study reported costs for the fifty electric powerplants in the United States that are currently emitting the largest quantities of sulfur dioxide.

Since each of the three contractor studies used different costing methodologies, it was necessary to readjust their cost figures so that they can be compared to one another and to the results obtained from the analysis already presented in this briefing. A description of the readjustment process is provided in the Appendix (see pages 19-20) along with further details of the specific cost data.

RESULTS FROM CONTRACTOR STUDIES

- TWO MODEL-BASED STUDIES:
  - CONTRACTORS: TEKNEKRON AND ICF
  - PURPOSE: TO COMPARE COSTS OF ALTERNATIVE REGULATORY APPROACHES
- SUPPLEMENTARY STUDY: COSTS ASSOCIATED WITH THE 50 LARGEST SO_2 EMITTERS IN U.S. (POWERPLANTS)
  - CONTRACTOR: PEDCO
  - PURPOSE: TO OBTAIN DATA RELEVANT TO SPECIFIC PLANTS.
- THESE STUDIES PROVIDE A COST DATA BASE ACROSS A RANGE OF EMISSION REDUCTIONS
- FOR PURPOSES OF COMPARISON WITH SIMPLE ANALYSIS, RESULTS HAVE BEEN NORMALIZED AND PRESENTED AS PRESENT VALUES.

SUMMARY AND COMPARISON OF CONTRACTOR STUDIES

This chart depicts the control cost estimates from the three contractor studies and DOE analysis. The horizontal axis indicates levels of emission reduction, in millions of tons of sulfur dioxide. The left vertical axis shows "present value" costs (in billions of dollars per million tons removed) and the right vertical axis shows the equivalent annual costs (in dollars per ton). The data points are keyed by contractor: the darkened circles represent results obtained from the ICF analysis; triangles represent Teknekron's results; and open circles represent PEDCO's results. The vertical lines show the range of costs obtained through the DOE analysis: their position on the horizontal axis represents fifty percent of the maximum reduction potential of the control method. The letters C,S, and D designate costs associated with coal cleaning, coal switching, or flue gas desulfurization, respectively. Undesignated symbols generally represent costs associated with a combination of control methods, although coal switching predominates in most cases.

The pair of dashed lines identifies a range of cost estimates. The lower line generally represents the costs associated with a regulation strategy which targets only those states and specific powerplants where sulfur dioxide reductions could be achieved for the least cost per ton controlled. Since cost-effective regulations are difficult to achieve in practice, the upper line represents actual regulations, which often compromise economic efficiency for equity concerns and administrative simplicity and are, therefore more costly.

The upward trend of the dashed lines can be attributed to "diseconomies of scale": as greater emission reductions are sought, the incremental costs of control increase. For example, higher reductions could require both scrubbing and switching to be employed at the same powerplant.

The control costs obtained by the DOE analysis generally agree with the control costs obtained by the more detailed contractor analyses.[1] Further, the results seem to indicate that coal cleaning is the least cost-effective and coal switching is the most cost-effective. Such a conclusion is not warranted, however, since indirect costs and possible benefits of particular methods are not considered. For example, benefits associated with the pre-cleaning of coal--lower ash content and more uniform quality--lower O&M costs to utilities. If these benefits are taken into account, the costs of coal cleaning attributable to sulfur dioxide removal may be comparable to those associated with other control methods. The uncertainties in all of the cost analyses indicate that the design of cost-effective regulations would allow individual utilities to select control methods best suited to their particular facilities.

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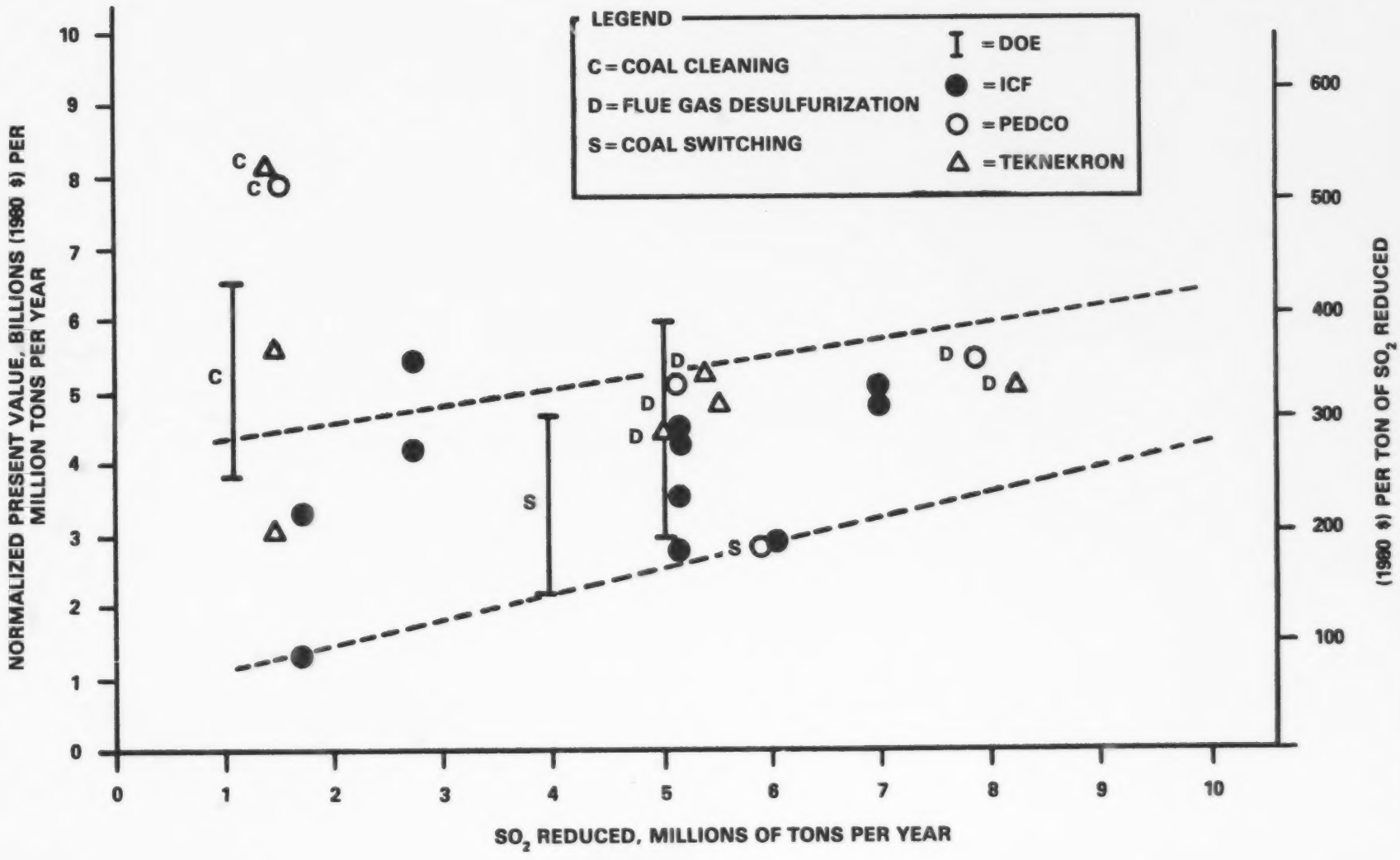
[1]Of course, there are uncertainties associated with the point estimates due to variations in the input data, modelling techniques and costing methodologies used by each contractor. The data shown in this chart have been adjusted (see Appendix pages 19-20) to account for different costing methods, however, small residual errors may remain. Uncertainties associated with input data and modelling techniques may be significant. Moreover, experience indicates that model analyses are likely to underestimate costs due to simplifying assumptions.

SUMMARY AND COMPARISON OF CONTRACTOR STUDIES



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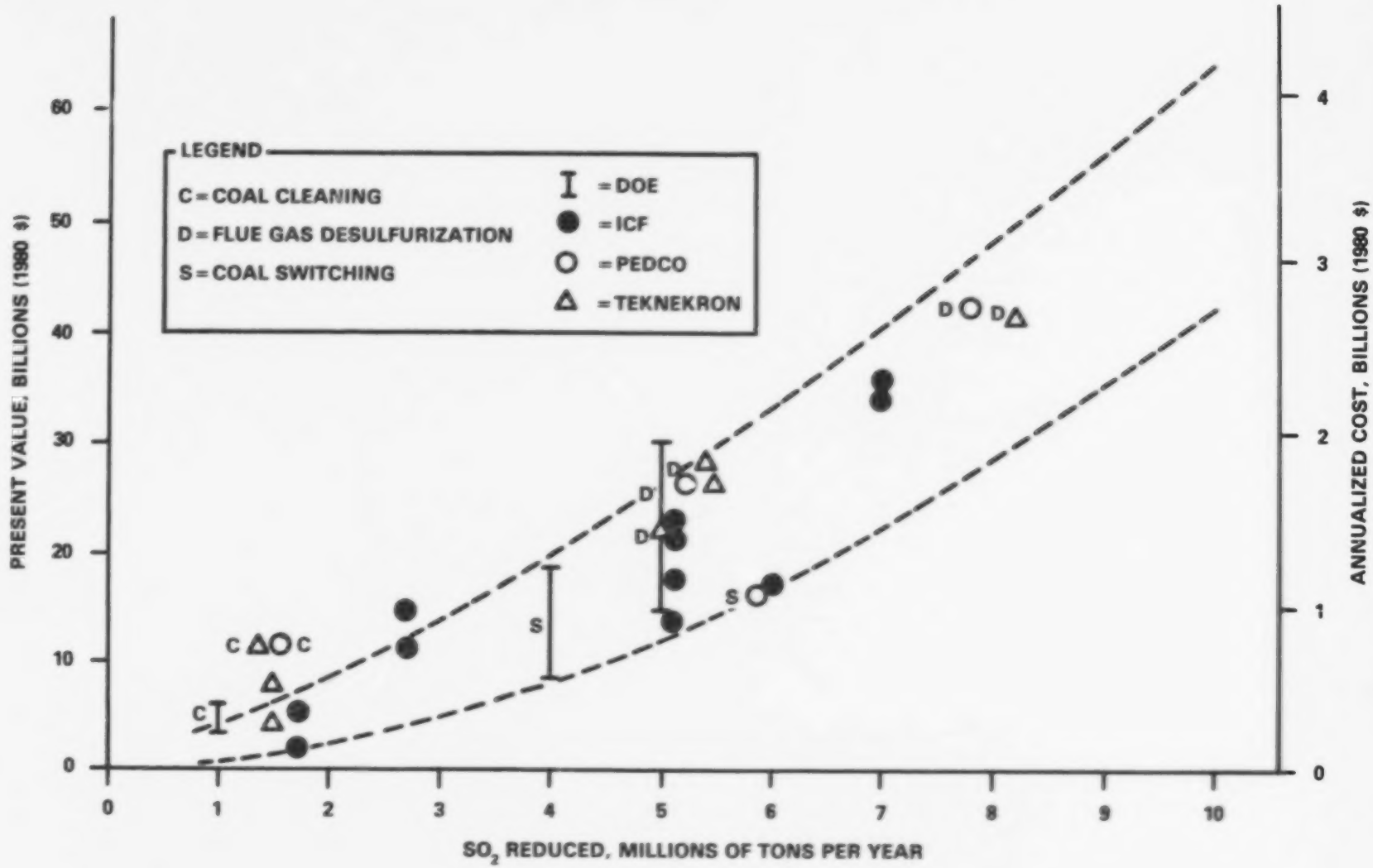
Total Costs

Although we have focused, for the purpose of analysis, on normalized costs (costs per unit of emission reduction), total costs are far more relevant to any decision to control sulfur dioxide emissions. This chart presents the same information as the previous chart but now the vertical axes represent the <u>total</u> present value (left scale) or annualized cost (right scale) of obtaining the emission reductions indicated along the horizontal scale. The pair of dashed lines curve upward, demonstrating the disproportionate rate at which costs increase as higher levels of emission reduction are sought.

Reading the chart, the costs of reducing sulfur dioxide emissions range between:

- $1 to $2 billion annually for a 5 million ton annual reduction (present value: $15 to $30 billion)
- $3 to $4 billion annually for a 10 million ton annual reduction (present value: $45 to $65 billion)

TOTAL COSTS



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MINIMUM ANTICIPATED COSTS TO CONTROL SO_2 EMISSIONS

This chart takes two levels of sulfur dioxide control from the previous chart and summarizes our best estimates of the minimum costs expected to be incurred to reach those control levels. The first column of numbers presents the costs associated with a decision to reduce annual sulfur dioxide emissions by five million tons. The second column presents the costs associated with a decision to reduce annual emissions by ten million tons.

The figures in each column represent alternative ways of describing the minimum costs that would be incurred by a decision to control sulfur dioxide emissions.

The first two costs shown in each column represent the annualized costs in 1980 dollars and the present value of the costs, again in 1980 dollars. These two accounting methods are often used in cost-benefit analyses in both the Government and private industry to compare alternative policies or investments. They are important accounting tools for decision makers; however, the costs they predict do not reflect actual expenditures.

The third row of numbers in each column represents our best estimate of the actual amount of dollars that would be spent over a 30 year period if there was no inflation. This type of cost reporting, i.e., uninflated dollars, is useful to those unfamiliar with the accounting intricacies associated with annualized or present value cost calculation procedures. The bottom row of costs in each column represents an estimate of the actual amount of dollars that would be spent over a 30 year period. To calculate these figures, we have assumed that the inflation rate over the entire 30 year period is only 6 percent. Higher rates of inflation would raise these figures while lower rates would decrease them.

There are, of course, uncertainties associated with these "best estimate" figures. Although a rigorous uncertainty analysis has not been done as part of this cost study, examination of the underlying data indicates that an uncertainty band of 25 percent is a reasonable estimate. It should be recognized, however,that the overall methodology used in this report generally underestimates rather than overestimates costs.

MINIMUM ANTICIPATED COSTS TO CONTROL SO_2 EMISSIONS

COST METHOD	5 MILLION TON ANNUAL REDUCTION	10 MILLION TON ANNUAL REDUCTION
Annualized (1980 $)	$1.3 Billion	$3.6 Billion
Present Value (1980 $)	$20 Billion	$55 Billion
30-Year Expenditures (1980 $)	$40 Billion	$110 Billion
30-Year Expenditures (Nominal $)*	$70-100 Billion	$200-300 Billion

* These figures assume a constant inflation rate of 6 percent; the range reflects differing ratios of capital and annual costs.

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CONCLUSIONS

Pages 39 through 41 summarize the conclusions of this report.

CONCLUSIONS

- WHEN PLACED ON A CONSISTENT ACCOUNTING BASIS, THE VARIOUS COST ANALYSES EXAMINED IN THIS REPORT ARE COMPATIBLE WITH ONE ANOTHER.

- THE CONTRACTOR ANALYSES DEMONSTRATE THAT CONTROL COSTS ARE HIGHLY SENSITIVE TO THE REGULATORY APPROACH APPLIED TO OBTAIN THE DESIRED EMISSION REDUCTION.

- CONTROL COSTS RISE DISPROPORTIONALLY AS GREATER LEVELS OF CONTROL ARE SOUGHT. FOR LARGER REDUCTIONS, LESS SULFUR DIOXIDE IS CONTROLLED PER DOLLAR EXPENDED SINCE:

  - CONTROL MEASURES MUST BE FORCED UPON UTILITIES BURNING LOWER SULFUR COALS OR HARD-TO-WASH COALS; AND

  - SHIFTS IN COAL SUPPLY AND DEMAND CAUSE COAL PRICES TO RISE.

- THE MINIMUM COSTS ARE LARGE FOR THE MASSIVE CONTROL PROGRAMS CURRENTLY ADVOCATED BY PROPONENTS OF IMMEDIATE CONTROL. FOR AN ANNUAL REDUCTION OF:

5 MILLION TONS	10 MILLION TONS
$1.3 BILLION (ANNUALIZED)	$3.6 BILLION (ANNUALIZED)
$20 BILLION (PRESENT VALUE)	$55 BILLION (PRESENT VALUE)
$40 BILLION (30-YEAR COSTS: REAL 1980 $)	$110 BILLION (30-YEAR COSTS: REAL 1980 $)
$70-100 BILLION (30-YEAR COSTS: NOMINAL $)	$200-300 BILLION (30-YEAR COSTS: NOMINAL $)

- THESE COSTS WILL BE BORNE PRIMARILY BY TEN MIDWEST STATES

- IT IS OUR JUDGMENT THAT THE ACTUAL COSTS OF CONTROL MEASURES WILL BE MUCH HIGHER THAN THOSE REPORTED HEREIN.
  - MAJOR COST ELEMENTS SUCH AS TRANSPORTATION COSTS AND THE PRICE RESPONSE DUE TO DISRUPTION OF THE COAL MARKET MAY BE SERIOUSLY UNDERESTIMATED.
  - ECONOMICALLY EFFICIENT REGULATIONS ARE UNLIKELY TO BE ACHIEVED IN PRACTICE.
- OF THE THREE CONTROL METHODS EXAMINED, NONE OFFERS SUBSTANTIAL ADVANTAGES OVER OTHERS.
- UNLESS EXTREMELY SMALL REDUCTIONS ARE SUFFICIENT, COAL CLEANING ALONE IS NOT A SATISFACTORY CONTROL METHOD.
- FLUE GAS DESULFURIZATION MAY BE AVOIDED BY UTILITIES DUE TO:
  - HISTORY OF MECHANICAL FAILURES AND MAINTENANCE REQUIREMENTS
  - CAPITAL INVESTMENT REQUIREMENTS
  - WASTE DISPOSAL PROBLEMS AND ENERGY EFFICIENCY LOSSES
- COAL SWITCHING INVOLVES SIGNIFICANT INDIRECT COSTS. FOR EACH MILLION TONS OF SULFUR DIOXIDE EMISSIONS REDUCED ANNUALLY,
  - 20 TO 25 MILLION TONS OF COAL CAPACITY WILL BE DISPLACED
  - 5100 TO 6400 MINERS WILL BE AFFECTED

- IT IS OUR JUDGMENT THAT THE UNCERTAINTY IN THE COSTS REPORTED IN THIS STUDY IS APPROXIMATELY 25 PERCENT.

  - THIS UNCERTAINTY IS INSIGNIFICANT WHEN COMPARED TO THE UNCERTAINTIES ASSOCIATED WITH CURRENT PROJECTIONS OF THE HEALTH, ENVIRONMENTAL OR ECONOMIC BENEFITS THAT WOULD BE ACHIEVED BY SUCH MASSIVE EMISSION REDUCTIONS. FOR EXAMPLE, REDUCING SULFUR DIOXIDE EMISSIONS BY TEN MILLION TONS PER YEAR MAY ONLY MARGINALLY DECREASE THE ACIDITY OF PRECIPITATION FALLING ON SENSITIVE AREAS.

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Calculations for Average Sulfur Content of Coal

Average sulfur content of coal is derived by summing the quantity of sulfur in various categories of coal and dividing by the total tonnage represented within the categories. Thus:

$(Q_x) \cdot (C_x) = S_x$ where: Q_x = percent sulfur content in category "x" coal

C_x = million tons of category "x" coal consumed in 1979

S_x = million tons of sulfur in category "x" coal

and:

$(S_T) \div (C_T) = A_T$ where: S_T = total million tons of sulfur, i.e., $S_x + S_y + \ldots S_n = S_T$

C_T = total million tons of coal, i.e., $C_x + C_y + \ldots C_n = C_T$

A_T = weighted average percent sulfur content

For >3% Sulfur Coal:

Coal Category	% Sulfur Content	Quantity Consumed	Quantity of Sulfur
3.0-3.5% S	3.25	66 million tons	2.15 million tons
3.5-4.0% S	3.75	23	0.86
4.0-4.5% S	4.25	17	0.72
4.5-5.0% S	4.75	0	0
5.0 & above	5.50	6	0.33
		112 million tons	4.06 million tons

(4.06 million tons sulfur) ÷ (112 million tons coal) = 3.6 average % sulfur

For >2% Sulfur Coal:

Coal Category	% Sulfur Content	Quantity Consumed	Quantity of Sulfur
2.0-3.0% S	2.50	89 million tons	2.23 million tons
3.0 & above	3.6	112	4.06
		201 million tons	6.29 million tons

(6.29 million tons sulfur) ÷ (201 million tons coal) = 3.1 average % sulfur

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For the purpose of the following calculations, the "weighted average sulfur content" will be used to identify the quantity of sulfur in the coal categories being examined. Thus, the quantity of sulfur in all coal greater than 3 percent sulfur will be defined as 3.6 percent. The quantity of sulfur in all coal greater than 2 percent sulfur will be defined as 3.1 percent.

Calculations for Coal Switching

A powerplant switching to low sulfur coal to reduce its sulfur dioxide emissions encounters both one-time capital costs and annual operation and maintenance (O&M) costs. Although either cost component can be expressed in several ways, we are concerned here with two representations: 1) costs per unit of coal switched, and 2) costs per unit of sulfur dioxide reduced.

I. CAPITAL COSTS

A. Capital costs per unit of coal switched can be calculated by determining the quantity of coal required to produce the power output of the plant, and multiplying this factor by the cost of upgrading precipitators and coal grinders. Such equipment improvements are necessary to enable the plant to burn low-sulfur coal and maintain compliance with particulate matter control regulations.

Thus: $\frac{\text{Capital Costs}}{\text{million tons of coal switched per year}} = K \times U \times E \times CE \times H$

where: K = equipment capital charge per kilowatt of capacity
U = capacity utilization per year
E = electricity conversion factor: kilowatt-hour/BTU (electrical)
CE = heat conversion efficiency: BTU (electrical)/BTU (thermal)
H = heat content of coal: BTU (thermal)/million tons of coal

For our analysis: K = $21 to $50/kw
U = 60% or 1 yr/(0.6 x 8760 hrs)
E = 1 Kwh/3412 BTU (electrical)
CE = 0.3 BTU (electrical)/1.0 BTU (thermal)
H = 24 trillion BTU (thermal)/million tons of coal

Therefore:

$$\frac{\text{Capital Costs}}{\text{million tons of coal switched per year}} = (21 \text{ to } 50) \times \left(\frac{1}{0.6 \times 8760}\right) \times \left(\frac{1}{3412}\right) \times (0.3) \times (24 \times 10^{12})$$

$$= \$8.45 \text{ million to } \$20.11 \text{ million}$$

B. Capital costs per unit of sulfur dioxide reduced are determined by dividing the previous results by a conversion factor translating tons of coal switched into tons of SO_2 removed.

Thus: $\frac{\text{Capital Costs}}{\text{million tons of } SO_2 \text{ removed per year}} = \left[\frac{\text{Capital Costs}}{\text{million tons of coal}}\right] \div (S \times EF \div W)$ (Conversion Factor)

where: S = change in percent sulfur
EF = emission factor: pound SO_2/ton of coal
W = weight conversion factor: pound/ton

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For our analysis: S = 2.6% change in sulfur from switching >3% S coal to 1% S coal, i.e., (3.6 - 1.0)

or

= 2.1% change in sulfur from switching >2% S coal to 1% S coal, i.e., (3.1 - 1.0)

EF = 38 lb. SO_2/ton coal
W = 2000 lb./ton

Therefore:

$$\frac{\text{Capital Costs}}{\text{million tons of } SO_2 \text{ reduced per year}} = [8.45 \times 10^6 \text{ to } 20.11 \times 10^6] \div (2.6 \times 38 \div 2000)$$
$$= \$171 \text{ million to } \$407 \text{ million (for switching >3\% S coal)}$$
or
$$= [8.45 \times 10^6 \text{ to } 20.11 \times 10^6] \div (2.1 \times 38 \div 2000)$$
$$= \$212 \text{ million to } \$504 \text{ million (for switching >2\% S coal)}$$

II. O&M COSTS

A. O&M costs per unit of coal switched reflect the fact that low sulfur coal is more costly than high sulfur coal. Therefore, we express O&M costs as the incremental difference in coal price.

Therefore:

$$\frac{\text{Annual O\&M Costs}}{\text{million tons of coal switched per year}} = \$6 \text{ million to } \$12 \text{ million (for switching >3\% S coal)}$$
or
$$= \$5 \text{ million to } \$11 \text{ million (for switching >2\% S coal)}$$

B. O&M costs per unit of sulfur dioxide reduced are determined by dividing the previous results by the conversion factor, introduced in Section I.B., translating tons of coal switched into tons of SO_2 reduced.

Thus: $$\frac{\text{Annual O\&M Costs}}{\text{million tons of } SO_2 \text{ reduced per year}} = \left[\frac{\text{Annual O\&M Costs}}{\text{million tons of coal switched}}\right] \div (S \times EF \div W)$$

where: S = change in percent sulfur (2.6% when switching 3% S coal; 2.1% when switching 2% S coal)
EF = emission factor: pound SO_2/ton of coal (38)
W = weight conversion factor: pound/ton (2000)

Therefore:

$$\frac{\text{Annual O\&M Costs}}{\text{million tons of } SO_2 \text{ reduced per year}} = [6 \times 10^6 \text{ to } 12 \times 10^6] \div (2.6 \times 38 \div 2000)$$
$$= \$121 \text{ million to } \$243 \text{ million (for switching > 3\% S coal)}$$
or
$$= [6.33 \times 10^6 \text{ to } 11 \times 10^6] \div (2.1 \times 38 \div 2000)$$
$$= \$125 \text{ million to } \$276 \text{ million (for switching > 2\% S coal)}$$

Calculations for Flue Gas Desulfurization

To illustrate the costs of flue gas desulfurization, we have examined a wet scrubber system installed on an existing high sulfur coal-burning powerplant.* A powerplant using a flue gas scrubber to reduce its sulfur dioxide emissions encounters both one-time capital costs and annual operation and maintenance (O&M) costs. Although either cost component can be expressed in several ways, we are concerned here with two representations: 1) costs per unit of coal scrubbed, and 2) costs per unit of sulfur dioxide reduced.

I. CAPITAL COSTS

A. Capital costs per unit of coal scrubbed can be calculated by determining the quantity of coal required to produce the power output of the plant, and multiplying this factor by the cost of a wet scrubber.

Thus: $\frac{\text{Capital Costs}}{\text{million tons of coal scrubbed per year}} = K \times U \times E \times CE \times H$

where: K = scrubber capital charge per kilowatt of capacity

U = capacity utilization per year
E = electricity conversion factor: kilowatt-hour/BTU (electrical)
CE = heat conversion efficiency: BTU (electrical)/BTU (thermal)
H = heat content of coal: BTU (thermal)/million tons of coal

For our analysis: K = $140 to $250/kw
U = 60% or 1 yr/(0.6 x 8760 hrs)
E = 1 Kwh/3412 BTU (electrical)
CE = 0.3 BTU (electrical)/1.0 BTU (thermal)
H = 24 trillion BTU (thermal)/million tons of coal

Therefore:

$$\frac{\text{Capital Costs}}{\text{million tons of coal scrubbed per year}} = (140 \text{ to } 250) \times \left(\frac{1}{0.6 \times 8760}\right) \times \left(\frac{1}{3412}\right) \times (0.3) \times (24 \times 10^{12})$$

$$= \$56.21 \text{ million to } \$100.37 \text{ million}$$

*Spray dryers are somewhat less expensive than wet scrubbers, however, these lower costs appear to be offset by a lower removal efficiency. Essentially, then, the overall costs of spray dryers overlap with the costs of wet scrubbers.

B. Capital costs per unit of sulfur dioxide reduced are determined by dividing the previous results by a conversion factor translating tons of coal scrubbed into tons of SO_2 removed.

Thus: $$\frac{\text{Capital Costs}}{\text{million tons of } SO_2 \text{ removed per year}} = \left[\frac{\text{Capital Costs}}{\text{million tons of coal}}\right] \div (S \times EF \div W) \quad \text{(Conversion Factor)}$$

where: S = change in percent sulfur
EF = emission factor: pound SO_2/ton of coal
W = weight conversion factor: pound/ton

For our analysis: S = 3.06% change in sulfur from 85% scrubbing of >3% S coal i.e., (3.6 x 0.85)

or

= 2.64% change in sulfur from 85% scrubbing of >2% S coal i.e., (3.1 x 0.85)

EF = 38 lb. SO_2/ton coal
W = 2000 lb./ton

Therefore:

$$\frac{\text{Capital Costs}}{\text{million tons of } SO_2 \text{ reduced per year}} = [56.21 \times 10^6 \text{ to } 100.37 \times 10^6] \div (3.06 \times 38 \div 2000)$$
= $967 million to $1726 million (for scrubbing >3% S coal)
or
$= [56.21 \times 10^6 \text{ to } 100.37 \times 10^6] \div (2.64 \times 38 \div 2000)$
= $1121 million to $2001 million (for scrubbing >2% S coal)

II. O&M COSTS

A. O&M costs per unit of coal scrubbed are calculated as a function of the amount of electricity produced by the powerplant.

Thus: $$\frac{\text{Annual O\&M Costs}}{\text{million tons of coal scrubbed per year}} = G \times E \times CE \times H \times D$$

Where: G = cost of scrubber O&M per kilowatt-hour generated
E = electricity conversion factor: kilowatt-hr/BTU (electrical)
CE = heat conversion efficiency: BTU (electrical)/BTU (thermal)
H = heat content: BTU (thermal)/million tons of coal
D = cost conversion factor: dollar/mill

For our analysis: G = 3 to 6 mills/Kwh
E = kwh/3412 BTU (electrical)
CE = 0.3 BTU (electrical)/1.0 BTU (thermal)
H = 24 trillion BTU (thermal)/million tons of coal
D = 1 $/1000 mills

Therefore:

$$\frac{\text{Annual O\&M Costs}}{\text{million tons of coal scrubbed per year}} = [3 \text{ to } 6] \times \left(\frac{1}{3412}\right) \times (0.3) \times (24 \times 10^{12}) \times \left(\frac{1}{1000}\right)$$

$$= \$6.33 \text{ million to } \$12.66 \text{ million}$$

B. O&M costs per unit of sulfur dioxide reduced are determined by dividing the previous results by the conversion factor, introduced in Section I.B., translating tons of coal scrubbed into tons of SO_2 reduced.

Thus: $$\frac{\text{Annual O\&M Costs}}{\text{million tons of } SO_2 \text{ reduced per year}} = \left[\frac{\text{Annual O\&M Costs}}{\text{million tons of coal scrubbed}}\right] \div (S \times EF \div W)$$

where: S = change in percent sulfur (3.06% for scrubbing >3% S coal; 2.64% for scrubbing >2% S coal)
EF = emission factor: pound SO_2/ton of coal (38)
W = weight conversion factor: pound/ton (2000)

Therefore:

$$\frac{\text{Annual O\&M Costs}}{\text{million tons of } SO_2 \text{ reduced per year}} = [6.33 \times 10^6 \text{ to } 12.66 \times 10^6] \div (3.06 \times 38 \div 2000)$$

$$= \$109 \text{ million to } \$218 \text{ million (for scrubbing} > 3\% \text{ S coal)}$$

or

$$= [6.33 \times 10^6 \text{ to } 12.66 \times 10^6] \div (2.64 \times 38 \div 2000)$$

$$= \$126 \text{ million to } \$252 \text{ million (for scrubbing} > 2\% \text{ S coal)}$$

Calculations for Coal Cleaning

For this analysis, a powerplant burning mechanically cleaned coal to reduce its sulfur dioxide emissions is assumed to encounter only increased fuel costs. Although capital expenditures are required for coal cleaning equipment and increased boiler efficiency may result from burning cleaned coal, for simplicity we will assume such costs and benefits to be incorporated in the cost of the cleaned coal. We will express the costs in two ways: 1) costs per unit of coal cleaned, and 2) costs per unit of sulfur dioxide reduced.

A. Annual costs per unit of coal cleaned are represented simply as the incremental cost of more expensive cleaned coal.
For our analysis, it is assumed that cleaned coal costs $3 to $5 per ton more than uncleaned coal.

Therefore: $\frac{\text{Annual Costs}}{\text{million tons of coal cleaned per year}}$ = $3 million to $5 million

B. Annual costs per unit of sulfur dioxide reduced are determined by dividing the previous values by the conversion factor translating tons of coal cleaned into tons of SO_2 reduced.

Thus: $\frac{\text{Annual Costs}}{\text{million tons of } SO_2 \text{ reduced per year}} = \left[\frac{\text{Annual costs}}{\text{million tons of coal cleaned}}\right] \div (S \times EF \div W)$

Where S = change in percent sulfur content
EF = emission factor: pound SO_2/ton of coal
W = weight conversion factor: pound/ton

For our analysis: S = 0.72% change in sulfur content after 20% cleaning of > 3% S coal, i.e., (3.1 x 0.20)
or
= 0.62% change in sulfur content after 20% cleaning of > 2% S coal, i.e., (3.1 x 0.20)
EF = 38 lb. SO_2/ton coal
W = 2000 lb./ton

$= [3 \times 10^6 \text{ to } 5 \times 10^6] \div (0.72 \times 38 \div 2000)$

Therefore: $\frac{\text{Annual Costs}}{\text{million tons of } SO_2 \text{ reduced per year}}$ = $219 million to $365 million (for cleaning > 3% S coal)

or

$= [3 \times 10^6 \text{ to } 5 \times 10^6] \div (0.62 \times 38 \div 2000)$
= $255 million to $424 million (for cleaning > 2% S coal)

Calculations for Present Value and Annualized Costs

To express one-time capital costs and annual O&M costs as a single cost figure, two basic methods may be used. The present value method discounts the annual stream of O&M costs as a single cost and adds the capital costs to represent the total sum needed to cover current and future costs over the life of the investment. The annualized cost method apportions the capital costs into annual payments and adds the O&M costs to represent the complete cost to be paid in each year of the investment life.

I. PRESENT VALUE (PV)

$$PV = C + \sum_{m=1}^{n} \frac{A_m}{(1+d)^m}$$

where: C = capital costs
A_m = O&M costs in year m (1980 $)
n = number of years in investment lifetime
d = discount rate

For our analysis: n = 30 years
d = 5 percent (real)
A_m is constant each year: $A_m = A$

Therefore:

$$PV = C + A(15.4)$$

II. ANNUALIZED COST (AC) in year m is expressed by the following:

$$AC_m = \frac{C}{\sum_{m=1}^{n} \frac{1}{(1+d)^m}} + A_m$$

where: C = capital costs
A_m = O&M costs in year m (1980 $)
n = number of years in investment lifetime
d = discount rate

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For our analysis: $n = 30$ years
$d = 5$ percent (real)
A_m is constant each year: $A_m = A$

Therefore:

$$AC_m = \frac{C}{15.4} + A$$

and is constant each year.

Calculations for Indirect Costs of Coal Switching

A shift in demand away from high sulfur coal and toward low sulfur coal will affect miners of high sulfur coal. To estimate the magnitude of the effect, we must first determine the number of miners employed per ton of coal mined. Using miner productivity factors of 9 tons of coal per day for deep mines and 28 tons per day for surface mines, and assuming a miner works 240 days per year, we derive the following:

(9 tons of coal mined/day) x (240 man-days/year) = 2160 tons of coal/miner/year from deep mines
(28 tons of coal mined/day) x (240 man-days/year) = 6720 tons of coal/miner/year from surface mines

Assuming that one-third of high sulfur coal is deep-mined and two-thirds is surface mined, we can express the number of miners as a function of the quantity of coal switched:

$$\frac{\frac{1}{3}\,(\text{1 million tons of coal switched})}{\text{2160 tons of coal/miner/year}} + \frac{\frac{2}{3}\,(\text{1 million tons of coal switched})}{\text{6720 tons of coal/miner/year}} = \text{254 miners/million tons of coal switched/year}$$

Ultimately, we can express the indirect costs of coal switching (i.e., effects on miners) as a function of the benefits of coal switching (i.e., sulfur dioxide reduced). To do this, however, we need to know the change in the sulfur dioxide emission rate from switching to low sulfur coal. Referring to Appendix page 17, where sulfur dioxide emission rates are derived, we can calculate the following:

$$\frac{\text{0.0684 ton } SO_2}{\text{ton >3\% sulfur coal}} - \frac{\text{0.0190 ton } SO_2}{\text{ton 1\% sulfur coal}} = \frac{\text{0.0494 ton } SO_2}{\text{ton coal switched}}$$ Decrease in emission rate from switching >3% sulfur coal to 1% sulfur coal*

while

$$\frac{\text{0.0589 ton } SO_2}{\text{ton >2\% sulfur coal}} - \frac{\text{0.0190 ton } SO_2}{\text{ton 1\% sulfur coal}} = \frac{\text{0.0399 ton } SO_2}{\text{ton coal switched}}$$ Decrease in emission rate from switching >2% sulfur coal to 1% sulfur coal*

Now, dividing these two emission factors into the number of miners affected per ton of coal switched, we obtain the following:

$$\text{(254 miners/million tons of coal switched/year)} \div \frac{\text{0.0494 ton } SO_2 \text{ reduced}}{\text{(ton >3\% sulfur coal switched per year)}} = \text{5132 miners/ton } SO_2 \text{ reduced/year}$$

and

$$\text{(254 miners/million tons of coal switched/year)} \div \frac{\text{0.0399 ton } SO_2 \text{ reduced per year}}{\text{(ton >2\% sulfur coal switched per year)}} = \text{6354 miners/ton } SO_2 \text{ reduced/year}$$

---

* Note that the reciprocal of these expressions yields the value for tons of coal switched per ton of sulfur dioxide removed: $\frac{\text{20.24 tons >3\% sulfur coal switched}}{\text{ton sulfur dioxide removed}}$ and $\frac{\text{25.01 tons >2\% sulfur coal switched}}{\text{ton sulfur dioxide removed}}$

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Calculations for Increase in Electricity Generation Costs

To estimate the increased cost of generating electricity at powerplants instituting sulfur dioxide controls, we will examine two control methods: (I) flue gas desulfurization; and (II) switching to low sulfur coal.

I. Flue Gas Desulfurization (FGD)

According to the cost assumptions presented on page 17 of the text, the capital costs of an FGD system range from $140 to $250 per kilowatt of capacity. Expressed in terms of the kilowatt-hours generated per year (at a 60 percent plant utilization rate), these costs are derived as follows:

$$\left[(\$140 \text{ to } \$250/\text{kw}) \div (0.6 \times 8760 \text{ hrs/yr})\right] \times (10^3 \text{ mills}/\$) = 26.6 \text{ to } 47.6 \text{ mills/kwh/yr}$$

The annual operation and maintenance costs (O&M) associated with an FGD system range from 3 to 6 mills per kilowatt-hour. To express the capital and O&M cost components as a range of total annualized costs, a 5 percent (real) discount rate is applied over a 30-year investment lifetime (as shown in the formula on Appendix pages 11-12) to yield the following:

$$\text{Annualized Cost}_{FGD} = \left[\frac{(26.6 \text{ to } 47.6 \text{ mills/kwh})}{15.4}\right] + (3 \text{ to } 6 \text{ mills/kwh}) = 4.73 \text{ to } 9.09 \text{ mills/kwh}$$

II. Switching to Low Sulfur Coal (SW)

Returning to the cost assumptions presented on page 17 of the text, the capital costs for upgrading plant equipment to handle low sulfur coal range from $21 to $50 per kilowatt of capacity. Expressed in terms of the kilowatt-hours generated per year (at a 60 percent utilization rate), these costs are derived as follows:

$$\left[(\$21 \text{ to } \$50/\text{kw}) \div (0.6 \times 8760 \text{ hrs/yr})\right] \times (10^3 \text{ mills}/\$) = 4.00 \text{ to } 9.51 \text{ mills/kwh/yr}$$

The annual operation costs for switching all coal greater than two percent sulfur to one percent sulfur coal are reflected in the higher purchase price of low sulfur coal. The price of greater than two percent sulfur coal ranges from $5 to $11 per ton, taking the average between prices for coal greater than three percent sulfur and prices for coal between two and three percent sulfur. To express these costs as a function of the kilowatt-hours generated per year, a factor relating coal burned to electricity generated is derived from the following formula:

$$\frac{\text{Kilowatt-hours}}{\text{ton of coal}} = H \times C \div E$$

$$= (24 \times 10^6) \times (0.3) \div (3412)$$

$$= 2110$$

Where: H = heat content of coal = 24×10^6 Btu (thermal)/ton coal

C = heat conversion efficiency = 0.3 Btu (electrical)/Btu(thermal)

E = electricity conversion factor = 3412 Btu (electrical)/kwh

Using the factor of 2110 kilowatt-hours generated per ton of coal burned, the annual operating costs associated with burning low sulfur coal are derived as follows:

$$\left[(\$5 \text{ to } \$11/\text{ton}) \div (2110 \text{ kwh/ton})\right] \times (10^3 \text{ mills/\$}) = 2.37 \text{ to } 5.21 \text{ mills/kwh}$$

To express the capital and annual operating cost components of coal switching as a range of total annualized costs, the formula on Appendix pages 11-12 is used to obtain the following:

$$\text{Annualized Cost}_{SW} = \left[\frac{(4.00 \text{ to } 9.51 \text{ mills/kwh})}{15.4}\right] + (2.37 \text{ to } 5.21 \text{ mills/kwh}) = 2.63 \text{ to } 5.83 \text{ mills/kwh}$$

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Calculations for Increase in Electricity Cost to Consumer

To estimate the maximum cost impact of sulfur dioxide controls on consumers of electricity, we will assume that the entire increase in electricity generating costs (derived on the previous two pages) is passed-through to the consumer. Further, assume that 85 percent of the electricity delivered to the consumer is generated by coal-burning powerplants instituting sulfur dioxide controls. (In actuality, this percentage varies from area to area, and in most cases less than 85 percent of the powerplants serving a given consumer would be high sulfur coal-burning plants subject to sulfur dioxide controls.)

In effect, then, the consumers in our example would see 85 percent of the increase in generating costs reflected in their electricity bills. To compare this increase to the amount consumers are paying now, page 25 of the text states that residential consumers in the 10-state region pay between 30 and 54 mills per kilowatt-hour for their electricity. Thus, the estimated cost increase is derived as follows:

$$\frac{(2.6 \text{ to } 9.1 \text{ mills/kwh}) \times (0.85)}{(30 \text{ to } 54 \text{ mills/kwh})} = 4 \text{ to } 26\%$$

Calculations for Maximum Control Method Effectiveness

Several factors contribute to the sulfur dioxide reduction potential of the three control methods, including: 1) the uncontrolled sulfur dioxide emission rates from burning greater than 3 percent sulfur coal and greater than 2 percent sulfur coal; 2) the volume of coal use to be controlled; and 3) the effectiveness of each control method in controlling sulfur dioxide. We have estimated the uncontrolled emission rates from greater than 3 percent and greater than 2 percent sulfur coal as follows:

$$SO_2 \text{ emission rate} = \frac{S \times EF}{W}$$

Where: S = percent sulfur content per ton of coal
EF = emission factor: pounds SO_2 per ton of coal
W = weight conversion factor: pounds per ton

If: S = 3.6% sulfur/ton of > 3% sulfur coal
EF = 38 lb. SO_2/ton of coal
W = 2000 lb. SO_2/ton SO_2

Then: SO_2 emission rate for >3% sulfur coal = $\frac{0.0684 \text{ ton } SO_2}{\text{ton coal}}$

Similarly, if:

S = 3.1% sulfur/ton of > 2% sulfur coal
(and the values for EF and W are unchanged)

Then: SO_2 emission rate for > 2% sulfur coal = $\frac{0.0589 \text{ ton } SO_2}{\text{ton coal}}$

Next, we assume that all of the high sulfur coal used by utilities in 1980 will be subject to sulfur dioxide controls. Referring back to the table on page 15 of the text, we find that 100 million tons of greater than 3 percent sulfur coal and 200 million tons of greater than 2 percent sulfur coal are consumed annually by utilities nationwide. We can calculate <u>total uncontrolled emissions</u> as follows:

$$(100 \times 10^6 \text{ tons of} > 3\% \text{ sulfur coal}) \times \left(\frac{0.0684 \text{ ton } SO_2}{(\text{ton} > 3\% \text{ sulfur coal})}\right) = 6.84 \text{ million tons of } SO_2 \text{ emitted from} > 3\% \text{ sulfur coal/year}$$

and

$$(200 \times 10^6 \text{ tons of} > 2\% \text{ sulfur coal}) \times \left(\frac{0.0589 \text{ ton } SO_2}{(\text{ton} > 2\% \text{ sulfur coal})}\right) = 11.8 \text{ million tons of } SO_2 \text{ emitted from} > 2\% \text{ sulfur coal/year}$$

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With the coal switching control method, these emissions will essentially be replaced by the emissions from one percent sulfur coal. Using the emission rate formula stated above:

$$SO_2 \text{ emission rate for 1\% sulfur coal} = \frac{0.0190 \text{ ton } SO_2}{\text{ton coal}}$$

Switching all of the greater than 3 percent sulfur coal to one percent sulfur coal potentially could yield total annual emission reductions of:

$$(6.84 \text{ million tons of } SO_2\text{/year}) - [(100 \times 10^6 \text{ tons switched per year}) \times \left(\frac{0.0190 \text{ ton } SO_2}{\text{ton 1\% sulfur coal}}\right)] = 4.94 \text{ million tons of } SO_2$$

Switching all of the greater than 2 percent sulfur coal to one percent sulfur coal potentially could yield total annual emission reductions of:

$$(11.8 \text{ million tons of } SO_2\text{/year} - [(201 \times 10^6 \text{ tons switched per year}) \times \left(\frac{0.0190 \text{ ton } SO_2}{\text{ton 1\% sulfur coal}}\right)] = 8.00 \text{ million tons of } SO_2$$

With the flue gas desulfurization control method, the uncontrolled emissions will be reduced by 85 percent. Scrubbing the emissions from all coal greater than 3 percent sulfur potentially could yield total annual emission reductions of:

$$(6.84 \text{ million ton of } SO_2 \text{ per year}) \times 0.85 = 5.81 \text{ million tons of } SO_2$$

Scrubbing the emissions from all coal greater than 2 percent sulfur potentially could yield total annual emission reductions of:

$$(11.8 \text{ million tons of } SO_2 \text{ per year}) \times 0.85 = 10.0 \text{ million tons of } SO_2$$

With the coal cleaning control method, the uncontrolled emissions would be reduced by 20 percent. Cleaning all coal greater than 3 percent sulfur potentially could yield total annual emission reductions of:

$$(6.84 \text{ million tons of } SO_2 \text{ per year}) \times 0.20 = 1.37 \text{ million tons of } SO_2$$

Cleaning all coal greater than 2 percent sulfur potentially could yield total annual emission reductions of:

$$(11.8 \text{ million tons of } SO_2 \text{ per year}) \times 0.20 = 2.37 \text{ million tons of } SO_2$$

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COMPARISON OF DOE ESTIMATES WITH CONTRACTOR ESTIMATES

The cost estimates plotted on pages 33 and 35 of the report are presented in tabular form on Appendix page 20.

The derivation of the DOE cost estimates has been presented in detail. Key assumptions in the DOE estimates are the real rate of return (5%) and the time horizon (30 years) (see Appendix, page 11-12).

The three contractors use different rates of return and time horizons. Therefore, the same capital (C) and annual costs (A) produce different present value (PV) and annualized costs (AC). In order to minimize such differences, the contractor's summary results have been adjusted to reflect, as far as possible, the DOE economic assumptions.

PEDCO summarizes results in terms of capital and annualized costs. PEDCO does not provide the discount rate or time horizon used to annualize capital costs; their annualization procedure is to divide capital costs by 7, indicating a high discount rate, a short time horizon or some combination of both. Therefore, PEDCO's annualized costs are not used. Rather, the annual costs provided by PEDCO (fuel plus O&M) are combined with their capital cost estimates using the relationship derived on Appendix pages 11-12; i.e., $AC = A + (C \div 15.4)$.

ICF presents annualized costs (in 1980 $) for each of four years: 1985, 1990, 1995 and 2000. ICF has recommended, however, that the 1990 annualized costs be used as most representative of the costs of the strategies analyzed. The present value of the ICF strategies is obtained by multiplying ICF's 1990 annualized costs by 15.4.

TEKNEKRON also provides estimates of Levelized Revenue Requirements (current dollars) over the 20 year period 1980-2000. The present value of this stream of constant annual costs is computed using TEKNEKRON'S real rate of return (5%), inflation rate (8%) and time horizon (20 years). The additional contribution to the present value of costs incurred between 2000 and 2010 must be estimated in order to conform to DOE's 30 year time horizon. This is done by (1) observing the cost trend between 1990 and 2000 reported by TEKNEKRON, (2) assuming the continuation of that trend between 2000 and 2010, (3) computing the present value of that 10 year cost stream, and (4) adding that discounted value to the present value computed from TEKNEKRON'S Levelized Revenue Requirements.

All three contractors employ valid economic procedures; the adjustments to the contractors' summary results are intended only to place all estimates on approximately the same economic footing.

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SO_2 CONTROL COST COMPARISON TABLE

Source	Strategy[1]	SO_2 Reduced (10^6 tons/yr)	Total Costs Present Value (10^9 $)	Total Costs Annualized (10^9 $/yr)	Normalized Costs Present Value (10^9 $)	Normalized Costs Annualized (10^9 $/yr)	Scrubbed Capacity (gigawatts)	Coal Affected[3] (10^6 tons/yr)
DOE								
	SWITCH	4 [2]	8.8 - 19	0.6 - 1.2	2.2 - 4.7	140 - 310	--	67
	FGD	5	15 - 30	1.0 - 2.0	3.0 - 6.0	190 - 390	39	--
	CLEAN	1	3.9 - 6.5	0.3 - 0.4	3.9 - 6.5	250 - 420	--	--
PEDCO								
	SWITCH	5.9	16.2	1.1	2.8	180	--	176
	FGD 60%	5.2	26.4	1.7	5.1	330	80	--
	FGD 90%	7.8	42.2	2.7	5.4	360	80	--
	CLEAN	1.5	11.9	0.8	7.9	520	--	--
ICF								
	10% REGIONAL	1.7	2.2	0.1	1.3	84	0.0	18
	10% EACH STATE	1.7	5.6	0.4	3.3	210	0.6	21
	4 LB. CAP	2.7	11.2	0.7	4.2	270	12.4	20
	4 LB. CAP + LCP	2.7	14.9	1.0	5.5	360	13.3	17
	15¢/LB. TAX	6.0	17.1	1.1	2.9	190	7.0	62
	30% REGIONAL	5.1	13.9	0.9	2.7	180	7.3	46
	30% REGION + LCP	5.1	17.8	1.2	3.5	230	9.1	32
	30% EACH STATE	5.1	21.7	1.4	4.3	280	8.6	45
	30% EACH + LCP	5.1	22.6	1.5	4.4	290	11.6	35
	2 LB. CAP	7.0	34.6	2.2	4.9	320	26	67
	2 LB. CAP + LCP	7.0	34.9	2.3	5.0	320	31	46
TEKNEKRON								
	4 LB. CAP	1.5	4.7	0.3	3.1	200	3.2	16
	4 LB. CAP + LCP	1.5	8.4	0.6	5.6	360	22	10
	2 LB. CAP	5.5	26.5	1.7	4.8	310	41	52
	2 LB. CAP + LCP	5.4	28.6	1.9	5.3	340	55	19
	30% FGD	5.0	22.0	1.4	4.4	290	43	14
	50% FGD	8.2	41.4	2.7	5.1	330	86	11
	CLEAN	1.4	11.5	0.8	8.2	530	-5.0	16

[1] Explanation of the strategies

- The terms "SWITCH," "FGD," and "CLEAN" refer to coal switching, flue gas desulfurization, and coal cleaning, respectively. These terms denote strategies which employ only these methods for reducing SO_2 emissions.
- PEDCO strategies apply only to the 50 powerplants which emit the most SO_2. The "60%" and "90%" designation after FGD refers to the amount of SO_2 reduction at each plant.
- All ICF strategies and the TEKNEKRON "CAP" strategies employ a mixture of SWITCH, FGD, and CLEAN control methods selected on a least-cost basis.
- The ICF "REGIONAL" strategies apply to 31 states east of the Mississippi River. Either 10% or 30% SO_2 emission reduction is obtained from the entire 31 state region at least cost, without regard to the location of emissions within the region.
- "EACH STATE" or "EACH" means that the percent reduction of SO_2 emissions is achieved at least cost within each state. Such strategies affect the 17 western states as well as the 31 eastern states. All costs estimated for the western states have been omitted for comparison purposes because other strategies affect only the eastern states.
- "LCP" means local coal protection. A constraint is placed on the least-cost, regional, or state approach such that 1990 production of high sulfur coal cannot fall below 1985 base case production in any coal supply area.
- "CAP" means an emission rate limitation applied to each powerplant. For example, "4 LB. CAP" means SO_2 emissions may not exceed 4 pounds per million BTU heat input.
- "15¢/LB. TAX" means all powerplants would be charged 15 cents for each pound of SO_2 emissions. Utilities are assumed to respond to such a tax by reducing emissions to the extent possible at less than 15 cents per pound. The costs shown are for emission control only; charges for residual SO_2 emissions are not included.

[2] The DOE SO_2 reductions are half of the theoretical maximums. These are assumptions rather than analytical predictions. The cost estimates follow from the assumed emission reductions.

[3] "Coal Affected" means the reduction in high sulfur coal demand relative to baseline estimates. Increases in low sulfur coal demand are not considered. The purpose is to provide an indication of the potential impact on the high sulfur coal industry, not on overall coal demand.

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